

Energy and Capacity Requirements for a 90% renewable system in New Zealand

Luke Schwartfeger*¹, Dr. Alan Wood,² Gari Bickers,³

¹ EPECentre, University of Canterbury

² Electrical and Computer Engineering, University of Canterbury

³ Transpower New Zealand

*Presenting author

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Abstract

This paper investigates the operation of New Zealand's electricity system replacing large thermal generation with different proportions of wind and geothermal generation. These portfolios are assessed with an implicit stochastic optimisation modelling tool that uses dynamic programming with backward recursion as the deterministic optimisation, and the forward simulation conducted with a weighted linear regression. The shortfall in generation capacity is identified for a range of generation and inflow scenarios, and the unserved energy is calculated.

As the development of the modelling tool is still in progress, the modelling tool and specific results presented in the paper are not final and will differ from those presented. However, the conclusions drawn from the results will likely be the same.

1. Introduction

As part of its commitment to reducing greenhouse emissions, New Zealand is considering electricity generation portfolios with a greater percentage of renewables. While greater than 80% renewable electricity supply has been achieved over the last three years, a recent report [1] recommended that 91% is necessary for 2050 emission targets.

New Zealand's electricity system is dominated by hydro generation which provides approximately 60% of the annual energy and 53% of the generation capacity [2]. However, the hydro storage can only store 10 weeks of average inflows meaning New Zealand energy security is at risk in years with low inflows. During low inflow years, thermal generation has been relied on to provide energy and conserve hydro storage. Thermal generation is also used to compensate for the mismatch between low autumn and winter inflows and high winter time demand.

New Zealand's electricity system consists of two AC systems (one for each island) which are connected by an HVdc link. The HVdc link is vital as 60-70% of electricity demand is in the North Island and the majority of hydro inflows, generation capacity and storage are in the South Island (80%, 70% and 84% of the national total respectively). The electricity supply also includes thermal co-generation, geothermal, wind and run-of-river hydro generation. Peak generation is above 6.8 GW and hydro generation capacity is only 4.5 GW, hence the other (particularly thermal) generation is required to meet peak demand.

The mostly likely candidates to replace thermal generation in New Zealand are wind and geothermal. Wind generation cannot be relied on to provide capacity but does produce predictable amounts of energy over month to year time spans [3]. Hydro storage can be conserved during high wind production periods and released during low wind periods [4]. Hence wind generation with hydro storage could be as effective an energy provider as thermal generation. Geothermal generation has the advantage of consistent energy production, which displaces other generation and potentially conserves hydro storage. Unfortunately, geothermal generation has a slow ramp rate so is unable to follow demand, consequently its installed capacity is limited by the minimum demand capacity unless it is operated on a seasonal basis.

Any isolated system that decommissions dispatchable thermal generation and replaces it with systems that depend on variable renewable resources (hydro inflows and wind) or baseload generation (geothermal) will require energy storage. Hydro reservoirs are an ideal storage medium, and it is expected that they will be used more intensively in energy systems with more renewable generation.

This paper evaluates candidate generation portfolios for New Zealand in which a large proportion of thermal generation is decommissioned and replaced by wind and geothermal generation. The unserved energy and maximum capacity shortfall of the portfolios will be compared to determine which system may best suit the transition to a 90% or more renewable grid. Other studies [5, 6] investigated peaking capacity requirements for 100% renewable generation scenarios but did not apply an optimisation-based modelling approach to manage hydro storage under inflow uncertainty.

2. Methodology

The study consists of two components:

- (1) Forming suitable generation portfolio scenarios
- (2) Modelling generation dispatch over a year under a range of inflow conditions. This includes optimisation of hydro reservoir management to manage the increasing variable requirements.

The generation portfolio selection process is explained, followed by description of the model of New Zealand's electricity system and the modelling tool developed to evaluate the scenarios. This description covers the hydro and electricity system representations and the implicit stochastic optimization program.

2.1 Generation Portfolios

New Zealand relies on a small number of thermal generation plants, the most significant of which are Huntly coal fired thermal station (500 MW) and the Taranaki Combined Cycle (TCC) plant (385 MW). This study assumes these two plants are decommissioned and replaced by one of four different combinations of wind and geothermal generation. Wind and geothermal generation were considered as there are 2529 MW and 300 MW of consented capacity, respectively [2]. Generation and demand data from 2015 was used and augmented to produce the study's scenarios. 2015 was selected as no significant generation has been added since this time.

To determine the amount of wind and geothermal generation to add, a hindcast simulation was conducted and found Huntly and TCC provided 4488 GWh. For each generation portfolio, the time series of wind and geothermal generation were scaled to provide this amount of energy. The generation portfolios, scaling factors and energy values are presented in Table 1.

Table 1. Scaling factors, added energy and total energy for generation portfolios

Portfolios	Wind			Geothermal		
	Scaling Factor	Added GWh	Total GWh	Scaling Factor	Added GWh	Total GWh
2015 Hindcast	1	0	1914	1	0	7246
50% Wind 50% Geo	2.172	2244	4158	1.310	2244	9490
67% Wind 33% Geo	2.563	2992	4906	1.206	1496	8742
83% Wind 17% Geo	2.954	3740	5654	1.103	748	7994
100% Wind 0% Geo	3.345	4488	6402	1	0	7246

2.2 Hydro and Electricity System Representations

There are five hydro schemes with significant storage in New Zealand, two in the North Island and three in the South Island. Each has a number of large and small reservoirs. To avoid the computational burden of modelling all the reservoirs, the hydro schemes are aggregated to two reservoirs. The inflows of the North and South Island differ substantially, both in scale and seasonality, while most North Island and South Island inflows are self-similar. This characteristic lends itself to New Zealand's hydro storage being aggregated to a two reservoir model [7, 8].

The aggregation involves two stages: (1) aggregation of each hydro scheme into a single reservoir, single generator representation, and (2) summing these representations to an island level. Minimum flow constraints are modelled by subtracting the minimum flows from the

inflow sequence, with any deficits defining the minimum storage series. Minimum flows result in generation and is applied as must-run generation. The aggregation converts inflows and storage to energy values.

The electricity system representation consists of two nodes, one for each island's AC system and one transmission constraint representing the HVdc link. The HVdc link's rated capacity is 1200 MW. As reserves have not been included in this model, to emulate this restriction, the transmission capacity is set to 700 MW transfer to the North Island and 800 MW transfer to the South Island, reflecting observed market outcomes.

This representation defines renewable energy inflows (hydro, geothermal and wind) and energy outflows (2015 demand) in both islands. It also defines hydro storage capacities; what is left is to optimize hydro reservoir management for these new scenarios.

2.3 Implicit Stochastic Optimisation (ISO)

The modelling tool developed is an implicit stochastic optimisation (ISO) approach [9] implemented in MATLAB. For this implementation of ISO, dynamic programming with backward recursion is the deterministic optimization [10], which is applied to 84 historical inflow sequences and results in 84 sets of optimal dispatch decisions for every half hour and for every possible combination of lake levels. This study considers wind, run-of-river, geothermal, cogeneration and demand as deterministic. A forward simulation determines a generation dispatch series using weighted linear regression to choose from the set of optimal decisions.

Backward Recursion (BR)

Each storage is discretized into 11 levels (n_{s_1} , n_{s_2}) and the modelling is conducted with I inflow sequences. The objective function is:

$$\min c_{t,s_1,s_2} = c_d[\hat{g}(t)] + c_f[\hat{s}(t+1)] + p_s[\hat{s}(t+1)] \quad (1)$$

Where c_{t,s_1,s_2} is the cost at t for the storage levels s_1 and s_2 , c_d is the dispatch cost, c_f is the future cost of the resultant storage levels, p_s is the minimum storage penalty. $\hat{g}(t)$ is the decision variable vector of dispatched generation and $\hat{s}(t)$ is the storage vector. The dispatch cost is the dispatched generation levels multiplied by the generation cost. Generation costs in increasing order are hydro, thermal and non-supply generation. The non-supply generation determines the unserved energy and capacity shortfall. The future cost is the cost at $\hat{s}(t+1)$ and is found by interpolating between the set of costs at $t+1$ (c_{t+1,s_1,s_2}), according to the storage that the generation dispatch vector leads to. The minimum storage cost is added as a penalty if the storage is less than required to ensure that the minimum flow constraints can be met. The objective function is solved as a mixed integer linear program, due to the piecewise linear form of the future cost function and the minimum storage penalty using a binary variable.

The constraints are transmission, generation and storage capacities, demand satisfaction and the energy balance equation:

$$\hat{s}(t+1) = \hat{s}(t) + \hat{f}_i(t) - \hat{g}_{hydro}(t) \quad (2)$$

where $\hat{f}_i(t)$ are the inflows and $\hat{g}_{hydro}(t)$ are the dispatched hydro generation which are equivalent to the water outflows.

Capacity shortfalls and the HVdc transmission constraint are generally associated with half hourly peaks. This is the justification of selecting a high resolution time increment of a half

hour, even though this imposes considerable computation time. As inflow sequences follow a seasonal pattern, and storage is too small to be carried over multiple years, the BR is applied to one year with a second year added to capture end-of-year effects. The output of each BR is optimal generation dispatches ($g_i^*(s_1, s_2, t)$) for each storage point and each time step.

Forward Simulation (FS)

To complete the ISO, a forward simulation is conducted using weighted linear regression across all optimal generation dispatches $g_i^*(s_1, s_2, t)$. For each forward simulation, an inflow sequence and initial storage value are selected. The optimal generation dispatch for each BR solution is found by linearly interpolating between the $g_i^*(s_1, s_2, 1)$ for the initial storage. This gives a range of optimal generation dispatch decisions, each associated with a scenario i , which are weighted and summed to produce the resultant generation dispatch decision. The next storage point is calculated with Equation 2. This is repeated till the end of the first year. This process results in dispatch decisions that depend on historical inflow sequences being a fair predictor of expected inflows. However, this is not necessarily the case – seasonal patterns are such that low lake levels are correlated with low future inflows.

Weights are applied to deter the forward simulation from driving the storage too high or low. New Zealand's storage reservoirs are mainly filled by flood events [11], so maintaining storage levels high runs the risk of spill, while maintaining storage levels low increases risk of non-supply of energy. The intention of the weights is to preferentially choose generation dispatches that release less water when storage is low and vice versa. The weights are calculated by comparing the forward simulation's storage to the perfect foresight storage associated with each scenario i . These perfect storage trajectories are pre-calculated by conducting a separate forward simulation with each $g_i^*(s_1, s_2, t)$ using the i -th inflow sequence (i.e. a perfect foresight simulation).

The weighting value is the normalised inverse Euclidean distance between the forward simulation storage and the perfect foresight storage at time t , where α is selected to be 10^5 to set the weighting distribution and d_i is the Euclidean distance (MWh):

$$w(i) = \left(\frac{1}{1+\alpha \cdot d_i} \right) / \sum_{j=1}^I \frac{1}{1+\alpha \cdot d_j} \quad (3)$$

For the very few low inflow sequences, storage will run out regardless of the weightings. In these cases, the forward simulation may dispatch hydro generation above the amount of water available. This deficit is added to the unserved energy.

3. Results

To assess the generation portfolios, forward simulations were conducted for each, using multiple historical inflow sequences. The sequences selected were those that supplied greater than or equal energy to the 2015 sequence as the amount of added wind and geothermal was determined by the thermal generation under the 2015 conditions. 50 inflow sequences were used. The start storage was taken from 2015 as well.

A generation portfolio's forward simulations produces 50 year-long generation dispatch series. The unserved energy is calculated by summing the total energy supplied by the non-supply generators. The capacity shortfall was the maximum half hour value over the year converted to MW. From this set of 50 series, unserved energy and capacity shortfall values are determined to characterise the generation portfolios. In all forward simulations, the percentage of renewable generation was above 91.2%.

Fig. 1 presents box-&-whisker plots of each generation portfolio, for unserved energy (left) and capacity shortfall (right). Fig. 2 presents the relationship between capacity shortfall and annual capacity factors.

As shown in Fig. 1, the unserved energy across all generation portfolios was less than 1.2 GWh excluding outliers. This is evidence that New Zealand's hydro storage is able to manage wind variability, enabling wind generation to be an effective energy supplier. The capacity shortfalls had hard minimum values of 220, 160, 101 and 42 MW for the four generation scenarios. The capacity shortfall decreased with increasing geothermal generation, as expected.

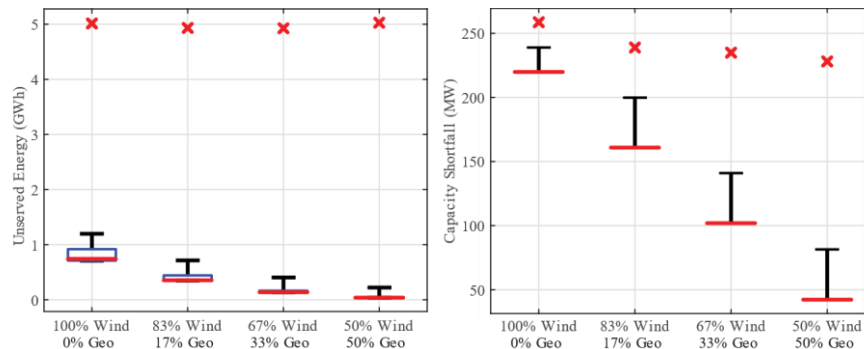


Fig. 1. Box-&-Whisker plots of Unserved Energy (GWh) and Capacity Shortfall (MW). Red line – Median; Blue Box - 25th and 75th percentiles; Black lines – Whiskers; Crosses – Outliers

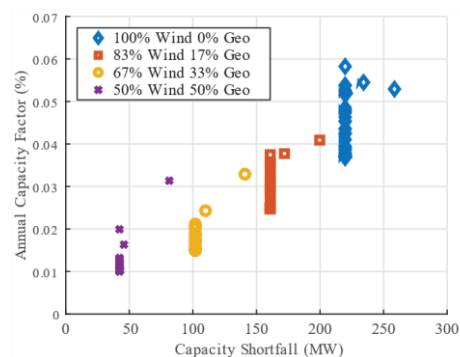


Fig. 2. Capacity Factor against Capacity Shortfall with outlier removed

The outliers in Fig. 1 are due the 1948 inflow sequence which only provides 25% of the annual inflow energy in the first 9 months. This sequence leads to a very low storage point in September at which point the non-supply generation produced the outlier values. With perfect foresight, this situation could have been better managed. This example highlights the difficulty of managing hydro reservoirs in New Zealand with highly variable and unpredictable inflow sequences.

Overall a capacity shortfall needs to be met by either peaking plant (thermal) or demand flexibility. As shown in Fig. 2 for capacity shortfalls of 42 to 260 MW, the capacity factors are between 0.01% to 0.06%, which is a very small amount of energy for a peaking plant to produce. The New Zealand electricity market is based on energy pricing which is unlikely to be able to compensate for the low hours of operation and the high uncertainty of operation for such a generator. While scarcity values of \$10k - \$20k / MWh can arise in the event of

shortfalls, the current market formulation make these prices quite difficult to achieve [12]. It indicates some sort of capacity incentive is required or demand flexibility is more aggressively pursued. Demand flexibility would be well suited to mitigate the capacity shortfall, as it is only required for a very small percentage of the time.

3 Conclusion and Future Work

This study investigated the energy and capacity requirements of New Zealand's electricity system where a large proportion of thermal generation was replaced with a range of combinations of wind and geothermal generation. It was found that New Zealand's hydro storage has sufficient capacity to manage wind variability, utilising all the energy generated by wind even with over 3 times the installed capacity. The greater the proportion of geothermal generation, the smaller the capacity shortfall.

The small capacity factors highlighted the fact that installing adequate capacity, or facilitating compensated demand curtailment, is more important than energy production for New Zealand to increase its renewable generation percentage.

Future studies need to include a wider variety of wind generation profiles, add inflow forecasting into the forward simulation and include reserve calculations to have a more accurate representation of the HVdc link capacity.

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